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Techno-economic analysis of the energy exploitation of biomass residues in Heraklion Prefecture—Crete

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Abstract

As with most of the Greek Islands, Crete is not interconnected to the national power grid. Therefore, power is generated locally and is based on a handful of ageing power plants running on imported diesel fuel oil, owned by the Public Power Corporation (PPC). However, the growth of the tourism industry and the subsequent need for more power present major challenges for the electricity production on the island. The high potential of biomass residues on the island creates new prospects for the energy concept of Crete. The purpose of this work is to examine the feasibility of a biomass-fired plant in the Heraklion Prefecture, on the island of Crete, taking into account the high biomass residues potential of this area.
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Keywords: Techno-economic analysis; Biomass residues; Feasibility study

Contents

1. Introduction . . . 363
2. Fuelling a biomass-fired plant . . . 363
3. Examination of the feasibility of the project . . . 363
   3.1. Biomass resources and exploitable biomass potential in the Heraklion prefecture . . . 364
      3.1.1. Terms and definitions . . . 364
      3.1.2. Available biomass quantities for energy production in the wider Heraklion prefecture . . . 365
      3.1.3. Technically available biomass quantities for energy production . . . 365
   3.2. Biomass thermochemical conversion technologies . . . 366
      3.2.1. Combustion combined with steam turbine . . . 366
      3.2.2. Integrated Gasification Combined Cycle . . . 366
      3.2.3. Gasification and Internal Combustion Engine (GasEng) . . . 367
      3.2.4. Pyrolysis and Internal Combustion Engine (PyrEng) . . . 367
      3.2.5. System efficiencies—a first approach . . . 367
      3.2.6. System capital costs—a first approximation . . . 367
      3.2.7. Bioelectricity technology selected . . . 368
4. Techno-economic viability of the project . . . 368
   4.1. Estimation of power plant economics . . . 368
      4.1.1. Financial figures of merit . . . 368
      4.1.2. Total Plant Cost . . . 368
      4.1.3. Updated estimation of plant efficiency and capital costs . . . 368
   4.2. Estimation of the plant's operating costs . . . 370

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4.2.1. Main operating parameters of the biomass combustion plant and Required Fuel Input (RFI) 370
4.2.2. Estimation of plant Total Operating Costs 370
4.2.3. Cost of Electricity 374
5. Viability of the project 374
5.1. Derivation of the project's financial figures 374
5.2. Sensitivity analysis 375
6. Conclusions. 376
References 376

1. Introduction

The demands of a thriving tourism industry and other commercial activities have placed an increasing strain on the Cretan power system. Blackouts are a regular occurrence during the busy summer months, when tourism swells the population by two to three times. Electricity demand on the island has risen steadily over the past 40 years, averaging an annual growth of about 7–8% in the last decade (1993–2006), as shown in Fig. 1 [1,2]. The Public Power Corporation (PPC) has recognised the need to expand and modernise the island's system and has made plans for an additional 280 MW_e of installed capacity (to add to the current installed capacity of 532 MW_e). However, the cost of supplying power to Crete is very high, since it includes transportation of fuel oil from the mainland. Since retail electricity prices are set nationally, the Cretan system incurs a substantial net loss to the company.

It is envisaged that power from a base-load power plant fuelled by local biomass resources, such as agricultural residues and by-products, will be cheaper than that from fossil-fuelled power stations. Therefore, the installation of a biomass-fired plant using this kind of fuel seems to be a promising solution for the energy problem of Crete.

2. Fuelling a biomass-fired plant

The fuel feedstock to be provided to a potential biomass-fired power plant is based on the extensive olive and olive oil production in Crete, and more specifically in the Heraklion Prefecture. Olive harvesting represents about 80% of all agricultural activities in Crete, 40% of which is located in the Messara Plain, in the southern part of the Heraklion Prefecture.

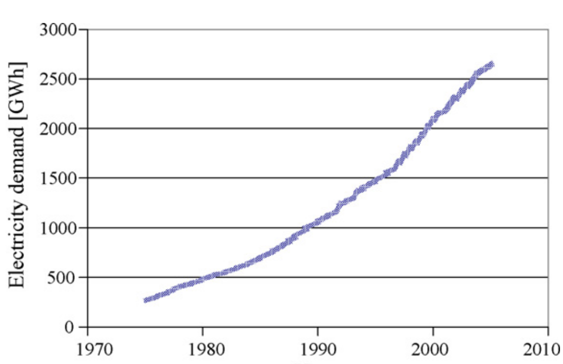

Fig. 1. Energy demand in Crete [1,2].

The Cretan farmers forward their annual olive harvests to the approximately 600 olive mills, which are located throughout the island and which represent the primary processing facilities. A number of by-products and residues arise from the harvesting and milling process, in particular:

- olive husk, the residual pulp of the olive, which is traditionally forwarded to large, secondary processing facilities to yield olive pit;
- trimmed leaves and twigs, which the mills must dispose of;
- olive tree prunings, which the farmers usually dispose of in large open fires within their farms.

Moreover, a number of other biomass residues of similar nature can be readily used to co-fire a central power facility, namely:

- vineyard prunings, which the farmers usually dispose of in a similar way to olive tree prunings (open fires);
- grape pomace, the residual pulp of the grapes, generated during the process of wine-making;
- greenhouse residues, the vast majority of which arise from the extensive greenhouse farming in the Heraklion Prefecture (Messara and Timpaki).

The utilisation of all or most of these residual and waste fuels in a central conversion plant, to generate energy, could also contribute to curbing the increasing environmental impact of the island's agricultural industry.

3. Examination of the feasibility of the project

It is widely accepted that any project is feasible provided that the basic economic figures are satisfactory. In the case of a biomass-fuelled power plant, the major goal is to deliver energy (electricity) at a reasonable cost. Additionally to this economical analysis, a sensitivity and risk analysis is also usually performed by some researchers in order to assess the economic profitability of the project [3].

However, these generic remarks have to be quantified and specific figures that will help decide whether the conceived project is feasible or not, have to be referenced upon. Some of these figures are listed below:

- the project Internal Rate of Return (IRR), which, in general, must be higher than those offered by other investment alternatives (i.e. bonds or other industrial projects);
- the Specific Investment Cost (SIC), i.e. an estimation of the capital cost of the plant, expressed as €/installed kW_e;
- the Cost of Electricity (COE), i.e. how much it costs to generate a unit of electricity, expressed in Eurocents/kWh_e (or ¢€/kWh_e).

The economic parameters listed above may be regarded as important milestones to determine the project feasibility, but it should also be noted that biomass projects are site- and fuel-specific, rather than projects falling in some general industrial norm.

However, some generic (rule-of-thumb) quantifications for these economic parameters can be given, based on existing experience. These quantifications, which are listed below, should not be regarded as strict economic figures, but rather as targets for commercial competitiveness:

- the project IRR (referring to own capital) should be above 15%, over 20 years;
- the Specific Investment Cost should be lower than €2000 per installed kW_e;
- the Cost of Electricity should be lower that 75% of the price of electricity purchased by the grid operator (which in the case of Crete is the Public Power Corporation), i.e. the COE should be lower than about ¢€6 kWh_e^{-1}.

Moreover, the available quantities of biomass resources should be adequate to sustain a minimum power plant size, so that the above targets are, indeed, realised.

In this paper, available biomass resources are assessed in the region of interest, i.e. the wider Heraklion Prefecture. The inventory of biomass processes that convert the fuel energy to electricity (thermochemical conversion) is also discussed, whereby useful information is derived, concerning process maturity, system efficiencies and capital costs. This data will provide vital information concerning the initial feasibility of the project and will be utilised at a later stage to quantify the economic parameters that determine the considered project's viability/profitability.

3.1. Biomass resources and exploitable biomass potential in the Heraklion prefecture

3.1.1. Terms and definitions

In a total of approximately 750 million productive olive trees worldwide, 97% is concentrated in the Mediterranean [4]. The Island of Crete is one of the main centres for olive and olive oil production in the Mediterranean, with olive harvesting representing about 80% of all agricultural activities in Crete. There are around 26 million productive olive trees on the island, 60% of which are located in the Heraklion Prefecture and especially in the Messara Plain, in the southern part of the Heraklion Prefecture.

There have been a number of studies to determine the exploitable biomass potential in the wider Heraklion Prefecture. In this context, some basic terms are briefly defined below, as used in this study:

- *Biomass resources*: In this study mainly the by-products and residues from the extensive olive and olive oil activities (cultivation, production, milling, secondary processing, etc.) in the Heraklion Prefecture and, secondly, other residues derived from agricultural activities (vineyards, greenhouses, etc.) are defined as biomass resources.
- *Exploitable biomass potential* (*also referred to as initially available biomass potential*): The quantities of biomass that can be obtained technically (i.e. with secured, well established logistics) and economically (i.e. with the fuel cost kept at a reasonable level, in order to sustain an economically feasible power plant operation).

Based on the above, a categorisation of biomass residues is carried out and presented in Table 1.

The vast majority of primary processing, i.e. from olives to first-quality (virgin) olive oil, is carried out in olive mills in the Heraklion Prefecture (a total of approximately 550 mills) that operate in the so-called 3-phase mode, whereas the olive mill produces olive oil, effluents and olive husk (the residual pulp of

Table 1
Biomass categories and designation for the various fuel types

Biomass fuel type designation[a]	Biomass category
By-products and residues from olive oil processing activities	
A1	Olive husk (from 3-phase olive mills)
A2	Liquid effluents from 3-phase olive mills
A3	Olive tree prunings (branches)
A4	Leaves and twigs (collected in the olive mills)
A5	Exhausted watery olive husk—EWOH (from 2-phase mills)
A6	Olive pit or kernel (from secondary processing of olive husk)
A7	Olive pit/kernel (from secondary processing of EWOH, see A5)
Residues from other agricultural activities	
B1	Vineyard prunings
B2	Grape pomace (clusters)
F1	Greenhouse residues

[a] Biomass fuel type designation follows the general categorisation pattern, first introduced by the author Vassilakos [5].

the olive with a 45–50% (w/w) moisture content). In the following stage, olive husk is forwarded to secondary processing units, in central, large secondary processors, where it is thermally processed to second-quality (refined) olive oil and to olive pit (a stony-type by-product with a 12–15% (w/w) moisture content).

An increasingly acute environmental problem is created in the 3-phase olive mill production chain, namely the generation of vast quantities of 3-phase olive mill effluents (see A2 in Table 1), which in an unregulated way, without any extensive treatment, are being disposed to holding ponds on site, or even into the local waterways. The very high organic load and acidity of these discharges are very harmful to the environment, not to mention highly odiferous.

Alternatively, an important variation of the traditional olive oil production chain (based on the 3-phase olive mill primary processing) has been proposed, namely the 2-phase olive mill, which, besides virgin oil produces a watery, pulp-type residue (with a moisture content of 65–70% (w/w) moisture), the so-called wet olive husk. In the next processing step, the wet olive husk is processed in large, centrifugal plants (the so-called repasso units), to produce secondary oil and exhausted wet olive husk (EWOH, see A5 in Table 1, with approximately 70% (w/w) moisture). The advantage of the 2-phase olive mills, which are extensively applied in Spain [6] is the elimination of the 3-phase generated liquid effluents (i.e. A2). However, this method generates large quantities of exhausted, wet olive husk (A5), which has to be disposed or further exploited, to secure the environmental benefits. In Spain, this is carried out in large energy plants, suitably coupled to the large repasso units, where a drying step of the EWOH is usually integrated in the energy plant.

Whether the olive oil production chain will be based on the 3-phase or the 2-phase olive mill configuration, it is a strategic choice, which reflects the political decision to treat the liquid wastes generated by the olive oil industry, either in a decentralised manner (autonomous treatment of effluents in the olive mills), or in a centralised one (large repasso plants, coupled with energy conversion units).

3.1.2. Available biomass quantities for energy production in the wider Heraklion prefecture

Due to:

a) the substantial biomass quantities generated in the Heraklion Prefecture,
b) the potential relief of the ever increasing power demand problem in Crete, and
c) the environmental advantages that could be derived (at least partially) by further exploiting the olive oil industry-generated by-products and effluents,

a number of efforts have been undertaken to assess the exploitable biomass potential, that can be initially available for a central biomass-to-energy plant.

The results of the most serious of these efforts are briefly summarised in Table 2.

3.1.3. Technically available biomass quantities for energy production

The above data refer to the initial (or exploitable) availability of biomass fuel types, in what concerns resource accessibility and competitive uses. The technical availability is further connected to organic matter losses during the various stages of feedstock logistics, prior to their final energetic utilisation in the power plant. These discrete logistics steps can be identified as collection, communition, transport, storage and drying. A realistic estimation of the technical availability of each of the above identified, logistics steps, for the different fuel types considered in this study, is shown in Table 3.

Based on the above, and taking into consideration the estimates of the initially available quantities for the different biomass fuel types, carried out by Zografakis [1], the Technically Available Fuel (biomass type) Quantities (or TAFQ) for power production in the Heraklion Prefecture, are listed in Table 4. Some preliminary data for a potential biomass-fuelled power plant are also given in this table, based on specific assumptions regarding plant availability and net electrical efficiency.

Table 2
Results from previous assessments, with regard to the exploitable (initially available) biomass potential for power generation in the wider Heraklion Prefecture (in dry tonnes/year)

Study	Fuel								
	Olive husk (3-phase) A1	Liquid effluents (3-phase) A2	Olive tree prunings A3	Leaves–twigs A4	Olive pit (3-phase) A6	Vineyard prunings B1	Grape pomace B2	Green-house residues F1	TOTAL (dry tonnes per year)
VIOTOPOS	–	–	18,375	–	48,960	5,820	–	9,400	82,555
IMPAX	26,294	23,429	14,158	6,333	–	10,796	18,486	21,500	120,996
ALTENER	26,294	23,429	14,158	6,333	–	10,796	18,486	21,500	120,996
NTUA	–	–	–	–	70,000	–	–	–	70,000
Zografakis	–	26,534	22,405	12,917	31,291	14,762	5,872	9,391	123,172

(1) VIOTOPOS (1993) initial data have been corrected for moisture and availability [7]. (2) IMPAX S.A. (1997) did not considered olive pit (A5) [8,9]. (3) The ALTENER Study (2000) was based on data initially provided by IMPAX and further verified during a 2-year dedicated field survey by NETWORK [10]. (4) NTUA (2001) performed the study for a Call for Tenders released by the Greek Regulating Authority for Electricity (RAE) and considered only olive pit (A5) [11]. (5) Zografakis (2005) did not consider olive husk (A1) [1].

Table 3
Technical availability of the various biomass fuel types, according to the different step of logistics, prior to end-conversion to energy

Fuel type	Stage efficiency (%)					Overall technical availability (%)
	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	
Olive tree prunings—A3	95	80	95	95	95	65.16
Leaves and twigs collected in the olive mills—A4	95	80	95	95	100	68.59
Olive pit (3-phase) olive pit-kernel (the dried by-product derived by the secondary olive husk processing—A6	95	100	95	95	100	85.74
Vineyard prunings—B1	95	90	95	95	95	73.31
Grape pomace—B2	95	100	95	95	95	81.45
Greenhouse residues—F1	95	100	95	95	90	77.16

1: Collection, 2: communition, 3: transport, 4: storage and 5: drying.

The specific assumptions considered here, upon which the power plant preliminary data have been derived, are:

- The Lower Heating Values (LHV) for the various fuel types are based on existing literature data [12].
- Power plant operating hours/year: 7223 (or, an overall availability of 82.45%).
- Net plant electrical efficiency (%): 23.0%.

3.2. Biomass thermochemical conversion technologies

The three process concepts that have been investigated, developed or implemented for the generation of electricity from biomass are presented in Fig. 2.

3.2.1. Combustion combined with steam turbine

The combustion of solid biomass is fully established and already widely used in various bioenergy applications, the most popular configurations being either grate (stoker) or fluidized bed designs.

Although grate-fired boilers are the norm for older biomass-fired plants, fluidized beds are rapidly becoming the preferred technology for biomass combustion. Fluidized bed combustors are very tolerant in variations of both feed size and moisture content (up to 30% on a w/w basis). Moreover, fluidized bed combustors exhibit superior environmental performance, especially regarding their low NO_x emissions. On the other hand, fuel ash content may represent a potential technical problem to fluidized beds, due to the increased risk of ash sintering which leads to bed material agglomeration.

The operating principle of a conventional biomass-fuelled power plant is based on the Rankine Cycle. Steam is produced in the boiler and expanded through a steam turbine connected to a generator producing electricity. The steam is condensed with cooling water or air. If the steam is condensed at a higher pressure, useful steam may be recovered (cogeneration). In the former case, more power will be produced and in the latter case by-product heat (process or district heat) is available [13].

3.2.2. Integrated Gasification Combined Cycle

The principle of an Integrated Gasification Combined Cycle (IGCC) Plant is as follows: dried (approximately 10–20% (w/w) moisture content) biomass is fed into a gasifier (in most cases, a Circulating Fluidized Bed—CFB-type reactor), where, with the provision of sub-stoichiometric air (autothermal), or water steam (allothermal, e.g. Battelle [14], BioHPR [15]) fuel gas is produced. The fuel gas is cleaned of alkali metals and solid particulates at an elevated temperature. The clean fuel gas (a lean fuel with a LHV in the range of 3–5 MJ/Nm^3 for autothermal and up to 10 MJ/Nm^3 for allothermal gasification) is combusted in a gas turbine and hot pressurised flue gases are expanded, raising steam in a Heat Recovery Steam Generator (HRSG) [16]. The steam produced drives a conventional steam cycle, producing additional electricity. The steam turbine can be either condensing (producing only electricity), or back pressure, in which case cogeneration of heat is possible.

Table 4
Technically Available Fuel Quantities (TAFQ) for biomass power production in the Heraklion Prefecture

Fuel #	Biomass fuel type	Biomass quantities (dry tonnes/year)		Fuel LHV (MJ/dry kg)	Plant technical data (preliminary)	
		Initially available	Technically Available (TAFQ)		Thermal power input (MW_{th})	Electrical power output (MW_e)
A3	Olive tree prunings	22,405	14,599	17.13	9.62	2.21
A4	Leaves and twigs	12,917	8,860	18.05	6.15	1.41
A6	Olive pit/kernel	31,291	26,829	20.12	20.76	4.77
B1	Vineyard prunings	14,762	10,822	17.84	7.42	1.71
B2	Grape pomace	5,872	4,782	19.14	3.52	0.81
F1	Greenhouse residues	9,391	7,246	16.84	4.69	1.08
	Total	96,638	73,138	18.55	52.16	12.00

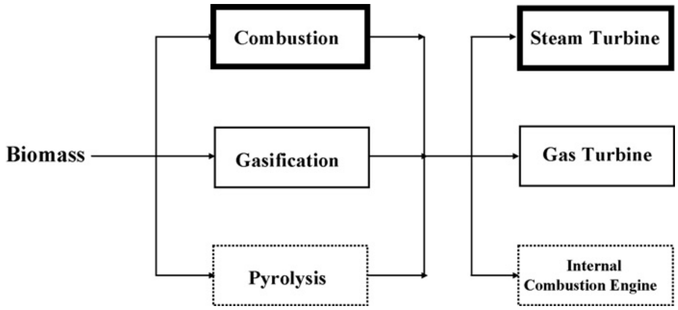

Fig. 2. Process configurations to be discussed (thicker boundaries denote more advanced applications, in commercial terms).

3.2.3. *Gasification and Internal Combustion Engine (GasEng)*

Relatively dry biomass (with a moisture content of 13–15%, w/w) is fed into a gasifier (moving bed, suitable for sizes up to 1.5 MW_e, or fluidized bed (Bubbling or CFB type), suitable for larger plants), where fuel gas is produced. The fuel gas is cleaned of tars and solid particulates. The clean fuel gas is then combusted in a modified diesel engine (Internal Combustion Engine—ICE) connected to a generator producing electricity. Cogeneration of heat is also possible.

3.2.4. *Pyrolysis and Internal Combustion Engine (PyrEng)*

Pyrolysis is the thermal degradation of biomass in the absence of an oxidizing agent, whereby the volatile components are vaporised by heating, leaving a solid residue of char and ash. The pyrolysis vapors and gases pass out of the reactor (pyrolyser) and are quenched (rapidly condensed) in a liquid recovery system. The pyrolysis liquid is a homogeneous mixture of organic compounds and water, in a single phase, and is a product of interest for power generation. The process which maximises the liquid fraction is known as Fast Pyrolysis.

For power production, the pyrolysis oils are employed as a fuel in an Internal Combustion Engine which is connected to a generator producing electricity.

Fast Pyrolysis is an interesting process, in that fuel production (pyrolysis oil, i.e. the energy carrier) may be decoupled from electricity generation. A thorough review of recent advances in Fast Pyrolysis technology can be found in literature [17–19].

3.2.5. *System efficiencies—a first approach*

The system efficiencies for the four biomass-to-electricity technologies analysed above, at capacities between 1 and 20 MW_e, are presented in Fig. 3 (adapted from Bridgwater et al. [20]). The efficiencies that are compared are net efficiencies, defined as ratios of net electricity output to the total fuel energy (fuel LHV) delivered to the power plant.

The difference in sensitivity to scale of the four biomass conversion systems is noticeable. The engine-based generators (PyrEng and GasEng) are relatively efficient even in smaller systems (<5 MW_e), however their efficiencies do not improve significantly as the system capacity increases. In contrast, the IGCC and Combustion system efficiencies improve consider-

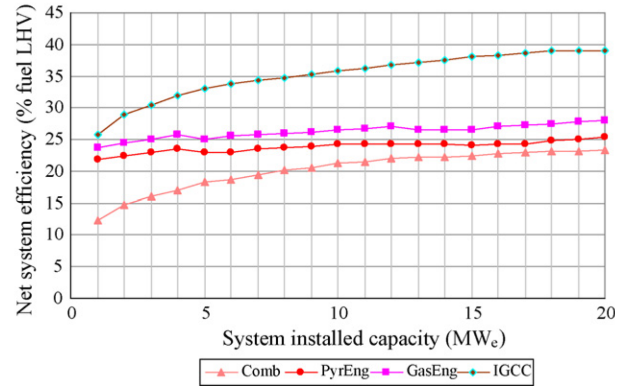

Fig. 3. Net system efficiency as a function of system capacity.

ably as system capacity increases. Thus, the IGCC efficiencies rise, to give a clear advantage of this technology over the other biomass systems, at large capacities (>15 MW_e). Similarly, the Combustion system's poor performance, in comparison to that of the engine systems at small scale, is counter-balanced by the greater rate of change in the system's efficiency at medium (approximately 7–10 MW_e) and higher power ratings.

3.2.6. *System capital costs—a first approximation*

System capital costs are compared in Fig. 4. The costs are Total Plant Costs (TPC) or ''turn-key'' costs, as described below, excluding any grants or subsidies. The TPC for the Combustion system are very well established. This has been made possible through many years of experience in combustors, boilers and steam cycles. These learning effects are not yet included in the costs for the other three systems and, as a result, their costs are higher. Hence, the Combustion system costs are based on 100th plant costs, which simply means that Combustion is an already mature technology, in comparison to the other three systems considered here.

A comparison of the curves in Figs. 3 and 4 reveals that higher efficiency is only achieved through higher capital expenditure. It should be realised that no single system combines high efficiency with low cost. Hence, no single system is the most suitable for all scales and optimisation is,

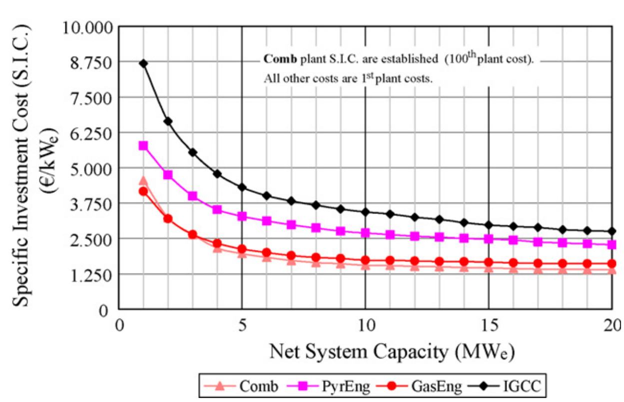

Fig. 4. Specific Investment Cost (SIC) as a function of system capacity.

indeed, required, depending on how system efficiencies and capital costs change with scale.

3.2.7. Bioelectricity technology selected

Based on the discussions and findings described above, on the technically available biomass resources in the Heraklion Prefecture, the alternative biomass conversion technologies that can be employed and the implications that the chosen scale (system capacity) of the biomass power plant can have on efficiency and capital costs, it is concluded that a combustion plant of about 8 MW_e installed capacity appears to be the most appropriate size for the specific application discussed in this study, i.e. the conversion of agricultural biomass produced in the Heraklion Prefecture to electricity. This choice is justified below:

1. combustion technology is by far the most advanced and readily available, commercially, technology of all four systems/technologies that were considered for the conversion of biomass energy to electricity (i.e. there is a substantially higher technological risk for the other three options);
2. the net efficiency (21–23%), at the power range of 8–12 MW_e, of a biomass Combustion system is an acceptable compromise among those of the power systems considered;
3. the Specific Investment Costs are leveled off at the power range selected above (8–12 MW_e), indicating that economies of scale are already significant at this power range.

Concluding, it may be stated that the selected biomass power plant size (8 MW_e) constitutes the best possible compromise between fuel availability in the wider Heraklion Prefecture (corresponding to around 67% of the Technically Available Fuel Quantities) and power plant economics (characterised by a leveling off of the plant's Specific Investment Cost).

4. Techno-economic viability of the project

The estimations described up to now have been derived taking into consideration generic studies on plant conversion efficiency and system capital costs. In the continuation of this article, more detailed estimates will be derived for a biomass combustion plant with an installed capacity of approximately 8 MW_e. The techno-economic viability of the project includes:

- An estimation of plant economics concentrating on updated figures of plant efficiency and on expected Total Plant Costs.
- An estimation of all the separate cost items that comprise the Total Operating Costs (TOCs), with special emphasis to fuel costs.
- A discussion of the sensitivity analysis of the project.

4.1. Estimation of power plant economics

4.1.1. Financial figures of merit

The four primary figures of merit are:

Net Present Value: Net Present Value (NPV) is the sum of all years' discounted after-tax cash flows. The NPV method is a valuable indicator, because it recognises the time value of money, therefore it is widespread used in the international literature [21]. Projects whose returns show positive NPVs are attractive.

Internal Rate of Return: Internal Rate of Return is defined as the discount rate at which the after-tax NPV is zero. The calculated IRR is examined to determine if it exceeds a minimally acceptable return, often called the hurdle rate. The advantage of IRR is that, unlike NPV, its percentage results allow projects of vastly different sizes to be easily compared.

Cost of Electricity: To calculate a levelised cost of energy (electricity) or COE, the revenue stream of an energy project is discounted using a standard rate (or possibly the project's IRR), to yield an NPV. This NPV is levelised to an annual payment and then divided by the project's annual energy output, to yield a value in ¢€ kWh^{-1}. The COE is often used by project evaluators to develop first-order assessments of a project's attractiveness. The levelised COE defines the stream of revenues that minimally meets the requirements for equity return and minimum debt coverage ratio. Traditional utility revenue-requirement analyses are cost-based, i.e. allowed costs, expenses, and returns are added to find a stream of revenues that meets the return criteria.

Payback Period: A payback calculation compares revenues with costs and determines the length of time required to recoup the initial investment. A Simple Payback Period is often calculated without regard to the time value of money. This figure of merit is frequently used to analyse retrofit opportunities, offering incremental benefits and end-user applications.

4.1.2. Total Plant Cost

In this study, all capital cost items have been incorporated in the so-called Total Plant Cost (or "turn-key" cost). As such, they include the costs of the basic equipment *plus* costs for erection, piping, instrumentation, electrical works, civil works, buildings, engineering, management, commissioning, contingency and interest during construction.

TPC has been used, so that realistic estimates of the total cost of constructing a working system can be calculated. It is important to recognise that capital costs can be quoted at various levels that include or exclude certain components of the TPC. These different levels are further indicated in Table 5.

The capital or investment cost reported in this study, represents the Total Plant Cost.

4.1.3. Updated estimation of plant efficiency and capital costs

Detailed studies [22] have estimated more precisely, than generic approaches [20], the net electrical efficiency and the capital costs (referred to as Total Plant Costs, see above) of biomass combustion plants, as a function of plant size. These data are based on biomass-fired power plant projects that have been realised and represent the current industrial state-of-the-art in biomass-fired Rankine power plants.

The net electric efficiency of modern condensing power plants based on woody biomass, as a function of plant size, is shown in Fig. 5.

Table 5
Components of capital cost estimates

Cost component	Usual range of costs	Cost factor used in the present study
Major equipment-item cost		
+erection		
+piping		
+instruments		
+electrical		
+civil works		
+buildings		
+lagging		
Direct Plant Costs (DPC)		100% DPC
Engineering, design, supervision	10–20% of DPC	15% DPC
Management overheads	5–20% DPC	10% DPC
Installed Plant Costs (IPC)		125% DPC
Commissioning	1–10% IPC	5% IPC
Contingency	0–50% IPC	10% IPC
Contractor's fees	5–15% IPC	10% IPC
Interest during construction	7–15% IPC	10% IPC
Total Plant Cost (TPC)		135% IPC 169% DPC

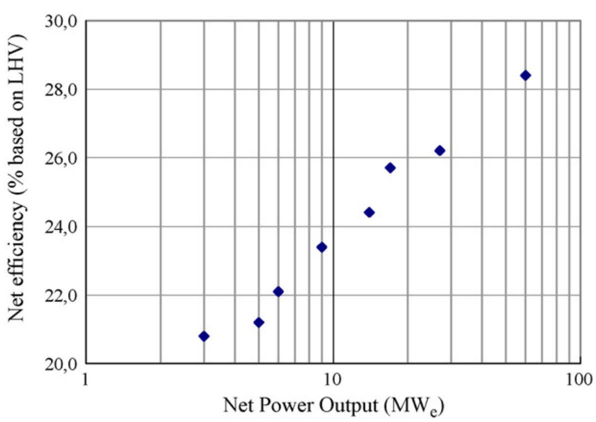

Fig. 5. Net electrical plant efficiency as a function of plant size.

Power plant investment costs of power plant projects that have been recently realised, representing accurately the capital costs of state-of-the-art combustion technology, are shown in Fig. 6. It is stressed that the investment cost refers to the Total Plant Cost paid by the customer, for a fully operating power plant.

The cost breakdown (as a percentage of TOC) for the different plant components is given in Table 6.

Fig. 7 depicts the Specific Investment Cost as a function of power output. From this graph, the importance of scale (plant size) is highlighted: Specific Investment Costs decrease from about €2500 kW_e^{-1} to approximately €1250 kW_e^{-1}, as power output is increased from 3 to 60 MW_e.

Based on the above findings, the following figures can be derived for the selected 8 MW_e biomass combustion plant, as far as the plant's efficiency and its capital cost are concerned:

- the net electrical efficiency of the plant will be between 22 and 24%, based on fuel LHV;
- the plant's capital cost (hereby denoting the Total Plant Cost) will be between €13 and 14.5 million, i.e. the plant's Specific Investment Cost will, most likely, lie in the range between €1600 and 1800 kW_e^{-1}.

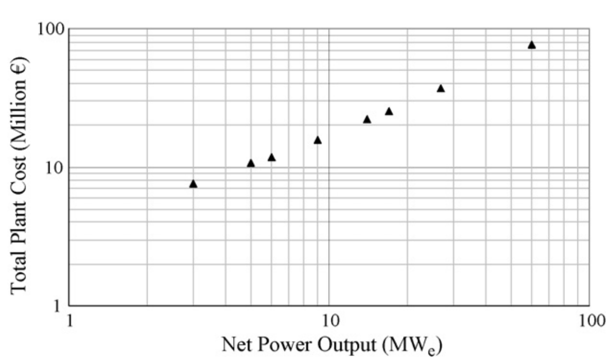

Fig. 6. Investment costs for biomass power plants as a function of plant size.

Table 6
Cost breakdown of the major power plant components

Task identity	Percentage of total cost
Boiler plant, fuel handing, stack	47.50
Turbine plant (cooling tower included)	13.75
Water-steam cycle, condensate system, feedwater system, auxiliary systems and equipment	13.75
Automation	12.50
Civil works	3.75
Others	8.75
Total	100.00

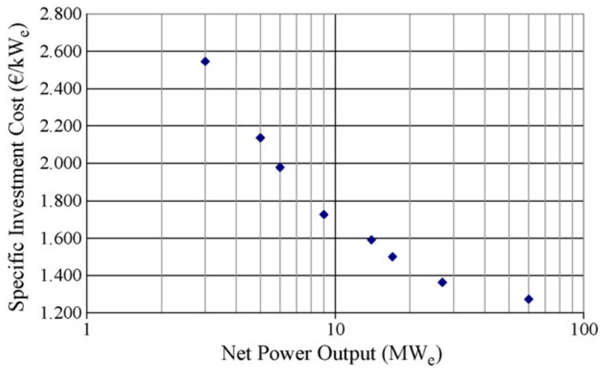

Fig. 7. Specific Investment Cost (SIC) for biomass-fired power plants as a function of plant size.

Table 8
Estimation of fuel requirements for the biomass combustion plant

Mean fuel mix LHV (on a dry basis) (MJ/dry kg)	18.74
Installed power (MW_e)	8.00
Plant net electrical efficiency (%)	23.00
Thermal power (MJ/s)	34.80
Plant availability (overall) (%)	82.45
Required Fuel Input (on a dry basis)-RFI(d) (dry tonnes/year)	48,288
Hourly fuel input (on a dry basis) (dry tonnes/h)	6.686
Mean fuel moisture content (as is) (% w/w)	37.08
Required Fuel Input (wet, as is)-RFI(w) (wet tonnes/year)	76,744
Hourly fuel input (wet, as is) (wet tonnes/h)	10.625
Mean fuel max LHV (wet, as is) (MJ/wet kg)	11.79
Fuel ash content (on a dry basis) (% w/w)	4.50
Total ash outflow (100% capture) (tonnes/year)	2173

In the specific case examined in this study, i.e. an 8 MW_e power plant fuelled primarily by the residues and by-products of the olive oil industry in the Heraklion Prefecture, the net electrical plant efficiency will be set at 23%, while the plant's Specific Investment Cost, referring to the Total Plant Cost, will be set at €1614 kW_e^{-1}. This last figure is equal to the maximum eligible SIC set by the most important subsidy programme applied to energy investments in Greece, for the period 2000–2006 (namely the Operational Programme for "Competitiveness"—OPC, implemented under the Community Support Framework III for Greece).

Baring the above figure for the Specific Investment Cost in mind, the Total Plant Cost will be approximately €12,920,000.

4.2. Estimation of the plant's operating costs

4.2.1. Main operating parameters of the biomass combustion plant and Required Fuel Input (RFI)

The main operating parameters for the 8 MW_e biomass combustion plant, considered here for the Heraklion Prefecture, are listed in Table 7.

Consequently, based on the figures presented in Table 7 and assuming a plant net electrical efficiency of 23% based on feedstock (biomass) mean Lower Heating Value of 17.20 MJ/dry kg, the yearly fuel requirements for plant operation, i.e. the Required Fuel Input, is given in Table 8.

Table 7
Main operating parameters of the 8 MW_e biomass combustion plant

Plant installed power (MW_e)	8.00
Equipment availability[a] (%)	85.0
Fuel availability[b] (%)	97.0
Levelised yearly availability (h/year)	7223
Electricity self consumption[c] (%)	6.0
Grid losses[c] (%)	2.0
Annual electricity production (net) (kWh/year)	53,255,180
Electricity purchase price[d] (€/kWh)	0.07779
Power capacity credit[d] (€/kW/month)	0.00000

[a] Refers to the annual percentage of time that the plant is available, i.e. not idle for repairs and overhaul.
[b] Refers to the annual percentage of time the Technically Available Fuel Quantities (TAFQ), are actually available.
[c] These figures are derived as mean values from the operation of similar biomass plants [22].
[d] By the Public Power Corporation (PPC).

It is noted that two different values for RFI are given depending on the moisture content of the final fuel mix:

i) RFI(d), which denotes the Required Fuel Input with regard to dry biomass;
ii) RFI(w), taking into consideration the actual moisture content of the different fuels.

Hence, the annual fuel consumption of an 8 MW_e biomass-fired combustion plant will be approximately 48,000 dry-tonnes/year or approximately 78,000 wet tonnes/year, with a mean moisture content of approximately 37%.

The above estimated RFI values for the proposed biomass power plant correspond to approximately 66% of the Technically Available Fuel Quantities that may be harnessed from the Heraklion Prefecture. Given the broad safety margins (with regard to initial availability, technical availability and actual plant requirements) adopted in this study, biomass supply is not considered to be a limiting factor for the smooth development of the project.

4.2.2. Estimation of plant Total Operating Costs

Once the capital costs of the biomass plant have been estimated, another important factor for the feasibility of the project, i.e. the power plant operating costs, has to be determined. The operating costs for a biomass combustion plant may be categorised into the items that are described below. The summation of all these operating cost items yields the Total Operating Costs for the biomass combustion plant under consideration.

4.2.2.1. Item 1: personnel (labour) cost. A generalized correlation for the number of required operating personnel per shift as a function of power plant capacity has been developed under relevant International Energy Agency (IEA) investigations [23,24]. This correlation estimates that, for a biomass combustion plant sized at about 8 MW_e, and assuming five shifts (three normal operating shifts + one back-up shift + one safety shift), 3 people are required per shift, i.e.

Table 9
Estimation of plant personnel costs (monthly and annual)

Personnel	Number of persons	Salary, per month (€)	Benefits[a], per month (€)	Total cost, per month (€)	Total cost[b], per year (€)
Shift supervisors	5	1,300	650	9,750	136,500
Operators	5	1,100	550	8,250	115,500
Operating staff costs	10			18,000	252,000
Maintenance manager	1	1,500	750	2,250	31,500
Mechanics	1	1,250	625	1,875	26,250
Electricians	1	1,250	625	1,875	26,250
Maintenance staff costs	3			6,000	84,000
Loaders/fuel system operators	2	1,100	550	3,300	46,200
Utility	1	1,250	625	1,875	26,250
Fuel-handling staff costs	3			5,175	72,450
Plant manager	1	2,000	1,000	3,000	42,000
Fuel manager	1	1,750	875	2,625	36,750
Accounts manager	1	1,500	750	2,250	31,500
Administrative assistant	1	1,100	550	1,650	23,100
Administration staff costs	4			9,525	133,350
Total personnel costs	20			38,700	541,800

[a] Figure includes all direct payroll overheads and are based on 50% of salary.
[b] Based on 14 months.

in total 15 operating staff for the day-round operation of the plant. In the case of the biomass-fired plant under consideration in the Heraklion Prefecture, where the fuel procurement period is limited to 3–4 months and fuel yard management may prove very demanding, plant personnel is expected to be higher. It is then estimated that there is a 25% increase in personnel above normal, i.e. the total number of persons is estimated at about 20 people. The required plant personnel and the associated costs (including all benefits) are summarised in Table 9.

4.2.2.2. Item 2: Operation and Maintenance (O&M) costs. Annual maintenance costs are assumed to be between 1.5 and 2.0% of the Total Plant Cost. So they are assumed to be 2% of TPC or €258,387.

4.2.2.3. Item 3: consumables. The major cost when considering the consumables for a biomass-fired plant are the costs for the purchase of chemicals (lime, for flue gas desulphurisation, and active carbon, for the removal of odors and other noxious gases) required for treating flue gases, as well as the costs related to sand replenishment (in case a fluidized bed combustor is employed). The calculation of the plant's annual cost for consumables is shown in Table 10.

It should be noted that the above costs are based on information provided to the authors by operators of similar plants worldwide and constitute the *maximum* consumables cost, which corresponds to a fluidized bed combustor (sand replenishment).

4.2.2.4. Item 4: general costs (overheads). General costs are usually calculated as overheads of the personnel costs and are assumed to be 10% of these costs. In the case considered in this study, the annual overhead costs are expected to be approximately €54,180.

4.2.2.5. Item 5: ash disposal costs. Ash disposal costs are associated with the costs necessary for the treatment of slag (bottom ash) and the solid residues derived from the treatment of flue gases (fly ash). Considering that (in the case of a fluid bed combustor) 40% of the total solid residues is withdrawn as slag (cyclones and boiler heating surfaces) and that the remaining 60% is removed as fly ash (in dust filters and other

Table 10
Calculation of the plant's annual cost for the consumables

	Chemical	Spec. consumption (kg/MWh net electricity delivered)	Consumption (tonnes/year)	Price (€/tonne)	Costs[a] (€/year)
3a	Sand	24.0	1278	20	25,562
3b	Lime	30.0	1598	73	116,629
3c	Active carbon	0.5	27	723	19,252
		Total annual cost of consumables			161,443

[a] Based on the net (i.e. delivered to the grid) annual electricity production of 53.255.180 kWh_e per year (see Table 7).

Table 11
Disposal costs (for solid residues)

In- and outflows	Percentage of ash input	Tonnes/year[a]	Treatment cost (€/tonne)	€/year
Ash input (in fuel)	100.00	2173		
Bottom ash	40.00	869	0[b]	0
Fly ash	60.00	1304	35[c]	45,632
			Total annual ash disposal costs	45,632

[a] Based on an annual ash production of 2173 tonnes (see Table 8).
[b] It is assumed that bottom ash can be safely landfilled or can be used as a construction material in a variety of applications.
[c] Fly ash needs treatment (usually inertisation with cement) prior to landfilling.

gas-cleaning devices), the annual costs associated with the treatment of these waste streams prior to their final disposal, are calculated in Table 11.

The above figure for fly ash treatment (€35 tonne^{-1}) is a figure found in the literature for the treatment of fly ash derived from the operation of Municipal Waste Incinerators. It is further noted that the above costs constitute the *maximum* ash treatment cost, which is considered to be that of a fluid bed combustor, because this type of combustor generates larger quantities of fly ash, due to severe bed material attrition, compared to a grate-type combustor.

4.2.2.6. Item 6: utilities. The main utility requirement is power to run all the plant's auxiliary equipment (pumps, blowers, fans, feeding systems, etc.). This cost item has already been accounted for, indirectly, since it has been calculated as a "loss" of efficiency, usually 6% of the gross power output, of the biomass plant (self consumption, as presented in Table 7) and, hence, as a "loss of revenue" through lower delivered electricity to the power grid.

Other costs related to utilities include:

- the cost of cooling water (which is limited in the case studied here, since an air-cooled condenser will be employed, due to the local scarcity of water);
- the cost of chemicals associated with the conditioning of the steam cycle working medium (i.e. water);
- other costs, such as diesel costs necessary for plant start-ups.

These utilities costs are assumed to account yearly for about 1% of Total Plant Costs. In the case considered here, the annual utilities cost is, thus, €129,193.

4.2.2.7. Item 7: contingency. Operating costs estimates are subject to various uncertainties, especially in regard to fuel costs and process uncertainties. In order to account for these uncertainties, a 10% overrun is assumed on the sum of all operating costs (except capital amortisation and fuel costs). In the present case, this constitutes an annual "expense" equal to the sum of the above (i.e. 1–6) cost items, that is €119,064.

4.2.2.8. Item 8: capital amortisation. It is assumed that around 30% of the total capital cost (or TPC) required to construct the plant will be borrowed over 15 years at an annual interest rate of 5% (nominal).

The annuity (i.e. interest and depreciation for the capital investment), X, is given by Eq. (1):

$$X = L \times \frac{r(1+r)^n}{(1+r)^n - 1} \quad (1)$$

where X is the annuity (€/year), L the borrowed capital (million €), r the interest rate (%) and n is the loan payback period (years).

Given that:

- the Specific Investment Cost (SIC) for the investment will be approximately €1614 kW_e^{-1}, as discussed previously;
- the loan is expected to be 30% of the investment cost (or €3,875,799);
- the interest rate is expected to be 5%;
- the loan payback period is expected to be 10 years.

then, the annuity for the proposed biomass-fuelled combustion plant is calculated from Eq. (1), to be €501,934 year^{-1}.

4.2.2.9. Item 9: fuel cost. The cost of biomass feedstocks (fuel cost) is considered a variable component, when it comes to calculating the Total Operating Cost, in order to determine the Cost of Electricity.

Moreover, the fuel cost consists of three different components, namely:

1. fuel acquisition cost (as is, where is);
2. fuel transportation cost, from the feedstock production site to the biomass combustion plant;
3. fuel processing cost (communition and/or drying).

Based on the authors' experience from similar studies [5], on similar biomass feedstocks and, also, on estimations derived from dedicated market surveys in the Heraklion Prefecture [10], the various fuel-cost components are estimated as described in the following paragraphs.

4.2.2.10. Item 9-I: fuel acquisition costs. With regard to the acquisition cost of the various fuels considered here (Tables 1 and 2), the following assumptions can be made:

Fuel types A3 and B1—olive tree prunings and vineyard prunings

The current practice for handling these types of residues is mainly open burning in the fields, i.e. they have a negative cost.

However, when a suitable fuel market will be established, these types of biomass fuels will no longer be for free. The IMPAX fuel assessment study [8] has determined a max. acquisition cost for the above fuel types of €8.80 (wet tonne)$^{-1}$.

Fuel type A4—leaves and twigs

This type of fuel is mainly collected at the primary processing plants, i.e. the olive mills. The disposal of this type of residue currently constitutes a major problem for the mills and, hence, its expected acquisition cost will be quite low. This cost is estimated [8] at €5.87 tonne^{-1}.

Fuel type A6—olive pit

Olive pit is an excellent fuel with high heating value and, hence, has already an established market and competitive uses. It is estimated, however, that it is possible to arrange long-term contracts for relatively high quantities (>5.000 tonnes/year) with the owners of this particular fuel, namely the secondary olive-husk processors. In this case, and based on already established market prices, the fuel acquisition cost for olive pit is estimated at €14.67 tonne^{-1}.

Fuel Types B2 and F1—grape pomace and greenhouse residues

These types of biomass fuels are currently considered unwanted residues and, thus, it will be relatively easy to establish a convenient market for them. It is estimated [8] that the maximum acquisition cost for both of these type of fuels will be €2.93 tonne^{-1}.

4.2.2.11. Item 9-II: transportation cost for the various biomass fuel types. The various fuel types considered in this study will be transported with trucks to the biomass power plant. Their transportation cost can be approximated on the basis of the following assumptions:

- Mean distance from the fuel production site to the power plant: 30 km
- Truck schedule (itinerary): $(2 \times 30) = 60$ km
- Truck mean speed: 40 km/h
- Schedule duration: $(60/40) = 1.5$ h
- Biomass truck-loading period: 0.5 h
- Total schedule duration: $(1.5 + 0.5) = 2$ h
- Number of schedules per day (8 h/day): $(8/2) = 4$
- Mean truck capacity: 30 m^3

Given that the average daily compensation (plus all associated costs) for a truck driver is approximately €220, the Specific Transportation Cost (STC, in €/dry kg) for the different fuel types is calculated by Eq. (2):

$$\frac{\text{total daily compensation (€)}}{(\text{number of schedules/day}) \times (\text{truck capacity}) \times (\text{specific gravity of the fuel (S.G.)}) \times (100 - \text{moisture content \% (M.C.)}/100)}$$

$$\text{or} \quad \frac{220}{4 \times 30 \times \text{S.G.} \times (100 - \text{M.C.\%}/100)} = 1.833 \times \frac{100}{\text{S.G.} \times (100 - \text{M.C.\%})}\ (\text{€/dry kg}) \tag{2}$$

where S.G. is the specific gravity for each biomass fuel type (kg/m^3) and M.C. is the moisture content for each biomass fuel type (% w/w).

The specific gravity and the moisture content for each of the biomass fuel types considered here are given in Table 12.

Finally, taking into account the above figures and the fact that the biomass combustion plant should be operated, as much as possible, on the cheaper feedstocks (with reference to the TFC (see Table 13) and not to the fuel acquisition cost alone), the Required Fuel Input (RFI(d), with reference to dry feedstock, see Section 3.2.4 above) Cost, or RFIC, is calculated as shown in Table 14.

Concluding, the total annual fuel cost for the proposed biomass combustion plant is €1,087,289.

Combining the above data on the percentage of each fuel type in the actual fuel mix, to be provided to the power plant (RFI(w)) and, also, the moisture content of the fuel types considered, the mean moisture content of the RFI(w) is calculated to 37.08% (w/w).

Consequently, the RFI(d) mean energy LHV is 18.74 MJ/dry kg or, the RFI(w) will be 11.79 MJ/wet kg. The RFI(d) mean cost is estimated to be €22.52 (dry tonne)$^{-1}$ and that of the

Table 12
Moisture content (M.C.) and specific gravity (S.G.) of the biomass fuel types considered in the present study [12]

Fuel type #	Biomass fuel type	Moisture content, M.C. (% w/w)	Specific gravity[a], S.G. (kg/m^3)
A3	Olive tree prunings	35.00	300
A4	Leaves and twigs (from the olive mills)	30.00	280
A6	Olive pit (from secondary processing)	18.00	350
B1	Vineyard prunings	37.00	325
B2	Grape pomace	65.00	450
F1	Greenhouse residues	50.00	300

[a] After chipping.

Table 13
Estimation of the Total Fuel Cost (TFC) for the various biomass fuel types, in reference to the Technically Available Fuel Quantities (TAFQ) for the Heraklion Prefecture

Fuel type #	Biomass fuel type	Fuel cost as is, where is (€/tonne)	Fuel cost where is (€/dry tonne)	Fuel transport cost (€/dry tonne)	Fuel processing cost (€/dry tonne)	Total Fuel Cost (TFC) (€/dry tonne)	Total Fuel Cost (TFC) (€/year)
A3	Olive tree prunings	8.80	13.54	9.41	2.93	25.89	377,902
A4	Leaves and twigs	5.87	8.38	9.36	2.93	20.67	183,155
A6	Olive pit	14.67	17.89	6.39	0.00	24.29	651,556
B1	Vineyard prunings	8.80	13.97	8.96	2.93	25.87	279,944
B2	Grape pomace	2.93	8.38	11.65	0.00	20.03	95,794
F1	Greenhouse residues	2.93	5.87	12.23	0.00	18.10	131,135
		Total Cost of Technically Available Fuel Quantities (TAFQ)					1,719,486

Table 14
Calculation of the Required Fuel Input (RFI), per fuel type, in the Heraklion biomass power plant and calculation of the Required Fuel Input Cost (RFIC)

Maximum installed power for TAFQ (MW_e)	Required Fuel Input, RFI(d) (dry tonnes/year)	Required Fuel Input, RFI(w) (wet tonnes/year)	Percentage of TAFQ in plant fuel mix	RFI energy content (GJ/year)	RFI thermal power (MW_{th})	Installed power per fuel type (MW_e)	Required Fuel Input Cost, RFIC (€/year)
2.21	4,200	6,462	28.77	71,946	2.77	0.64	108,719
1.41	8,860	12,657	100.00	159,916	6.15	1.41	183,155
4.77	20,000	24,390	74.55	402,400	15.48	3.56	485,709
1.71	3,200	5,079	29.57	57,088	2.20	0.50	82,777
0.81	4,782	13,664	100.00	91,535	3.52	0.81	95,794
1.08	7,246	14,492	100.00	122,024	4.69	1.08	131,135
12.00	48,288	76,744	66.02	904,910	34.80	8.00	1,087,289

RFI(w) €14.17 (wet tonne)$^{-1}$ respectively. On an energy basis, the mean cost for the fuel mix will be €1.20 GJ^{-1}.

4.2.2.12. Item 10: reciprocity fees to the Local Authorities. According to the Greek Joint Ministerial Decision Δ6/Φ1/11444 (ΦΕΚ 826/28.06.2001), every RES electricity-producing station is subject to an annual charge, in the form of a special annual fee (reciprocity charge), equaling 2% of the station's electricity sales to the public grid. This charge is collected by the Electricity System Operator (in the case of islands, this is PPC) and it is given to the Local Authorities, within the area of which the RES station operates, for the purpose of realising local development projects.

For the proposed 8 MW_e biomass plant, producing annually 53,255,180 kWh, the above annual reciprocity fees amount to about (2%) × (€0.07779 kWh^{-1}) × (53,255,180 kWh) = €82,854 year^{-1}.

4.2.3. Cost of Electricity

Based on the above figures, the operating costs (including contingency, amortisation and fuel cost) for the proposed 8 MW_e biomass combustion power plant can now be summarised in Table 15, where the relative weight of each operating-cost item in the Total Operating Cost is also shown.

Based on the data of Table 7 (the plant's main operating parameters) and on the above calculation of TOC, the Cost of Electricity for the biomass-fuelled power plant under consideration can now be derived, as shown in Table 16.

As seen from the above table, the COE is quite high (approximately 72% of the actual purchase price of electricity by PPC), with the fuel cost comprising approximately 37% of the Total Operating Cost. This means that relatively slight changes in feedstock cost have large impacts on the COE and the biomass system under consideration is, thus, quite sensitive to feedstock costs.

5. Viability of the project

5.1. Derivation of the project's financial figures

Once the main parameters of the biomass-fuelled combustion plant under consideration (8 MW_e, in the Heraklion Prefecture), the Total Plant Costs and the Total Operating Costs have been established and correlated with the plant's main

Table 15
Summary of operating costs for the proposed biomass combustion plant

Item #	Operating Cost Item	(€/year)	(%)
1	Personnel Costs	541,800	18.17
2	Operation and Maintenance (O&M) Cost	258,387	8.67
3	Consumables	161,443	5.41
4	General Costs	54,180	1.82
5	Fly ash disposal	45,632	1.53
6	Utilities	129,193	4.33
7	Contingency	119,064	3.99
8	Amortisation	501,934	16.83
9	Fuel cost	1,087,289	36.46
10	Reciprocity fees (to Local Authorities)	82,854	2.78
	Total Operating Cost (TOC)	2,981,776	100.00

Table 16
Cost of Electricity (COE) under various conditions for the proposed biomass power plant (in €/kWh$_e$ delivered)

Condition with regard to operating cost items included in COE	€/kWh$_e$
Only fuel cost (item #9) included	0.02042
All operating costs included, except Fuel Cost (item #9) and amortisation (item #8)	0.02615
All costs included, except Fuel cost (item #9)	0.03557
All operating costs included	0.05599
Purchase price of electricity (by PPC, see Table 7)	0.07779

operating parameters, the feasibility of the project can be further examined.

The figures related to project investment (with regard to Total Plant Costs), project financing (including loan assumptions) and power plant operation are summarised in Table 17.

Based on the above figures, the financial evaluation of the proposed project (i.e. the implementation and operation of an 8 MW$_e$ biomass-fuelled combustion power plant in Heraklion Prefecture) is given in Table 18.

The project's pay-back period on own capital is further shown graphically in Fig. 8.

5.2. Sensitivity analysis

The sensitivity of the project under consideration is examined with regard to two specific parameters, which are expected to have a major impact on the project's viability. These two parameters are:

Table 17
Summary of project investment, project financing and power plant operation parameters and costs

	%	€
Investment (TPC)		
Civil works	10.00	1,291,933
Electromechanical equipment	60.00	7,751,598
Other expenses	30.00	3,875,799
Total	100.00	12,919,330
	%	€
Project financing		
Own capital	30.00	3,875,799
OPC subsidy (see Section 3.2.3)	40.00	5,167,732
Long-term loan	30.00	3,875,799
Total	100.00	12,919,330
Loan assumptions		
Taxation coefficient (%)		35.00
Interest (%)		5.00
Pay-back period (years)		10
Grace period (years)		2
Power plant operation (€/year)		
Yearly income (sales of electricity)		4,142,720
Yearly expenses (=TOC − amortisation)		2,479,859
EBIDTA (earnings before interest, depreciation and taxes)		1,662,863

Table 18
Financial evaluation of the proposed project

Discount rate (%)	15.0
WACC (%)	10.0
IRR own capital, 10 years (%)	20.0
IRR own capital, 20 years (%)	24.4
Own capital pay-back period (years)	6.7
NPV (own capital), 10 years (€)	722,909
NPV (own capital), 20 years (€)	2,080,614

- the cost of biomass feedstock, i.e. the most important cost item, in terms of weight in the Total Operating Cost;
- the Specific Investment Cost, a factor which basically determines the Total Plant Cost.

The project IRR is given in Fig. 9 as a function of fuel cost, for three different values of SIC. Assuming an acceptable project IRR of 15%, the importance of fuel cost on project viability is clearly shown. The RFI(d) mean cost (Required Fuel Input, with respect to the dry biomass input), calculated at approximately €22.5 (dry tonne)$^{-1}$, clearly shows that viable projects, in terms of IRR, may arise for Specific Investment Costs lower than approximately €1650 kW$_e$$^{-1}$. In case of cheaper, but more difficult to handle, biomass feedstocks (such as the Exhausted Wet Olive Husk), higher efficiency technologies may be applied (resulting in higher SIC), which may incorporate an integrated (to the power plant) feedstock-drying stage.

Finally, the importance of fuel cost on the Cost of Electricity is clearly seen in Fig. 10, where the Total Operating Cost, and, hence, the COE, is depicted as a function of fuel cost. The impact of fuel cost on COE is profound, as already discussed in Section 3.2.6. Higher cost feedstocks severely diminish the project's profit margin (defined as the difference between the electricity purchase price (by PPC), referred to in Table 7, and the Total Operating Cost) and, hence, worsen project viability. On the other hand, the need for introducing cheaper feedstocks in the plant's fuel mix (such as the Exhausted Wet Olive Husk, see above) becomes an essential factor of project viability.

The large impact that fuel costs have on COE and, hence, on the viability of the project into consideration, imposes considerable risks on project implementation. Besides investigating the use of lower cost biomass feedstocks, serious efforts must be undertaken to secure the majority of the RFI stream, through long-term fuel contracts, indexed in such a way that a potential increase in fuel costs is less, or at least equal, to any increase in the electricity purchase price (by PPC).

Another important factor, which requires further investigation, is the annual operating time of the plant. Throughout this study it is assumed that, being a base-loader, the power plant under consideration will have no difficulties delivering all its generated electricity to the grid. However, it is possible that in periods of low demand, PPC will activate cut-offs to all Independent Power Producers (IPPs), to comply with the technical constraints of its own fossil-fuel-based power stations. In this case, the penetration of the biomass power plant will be lower than expected (i.e. lower than 100%), which,

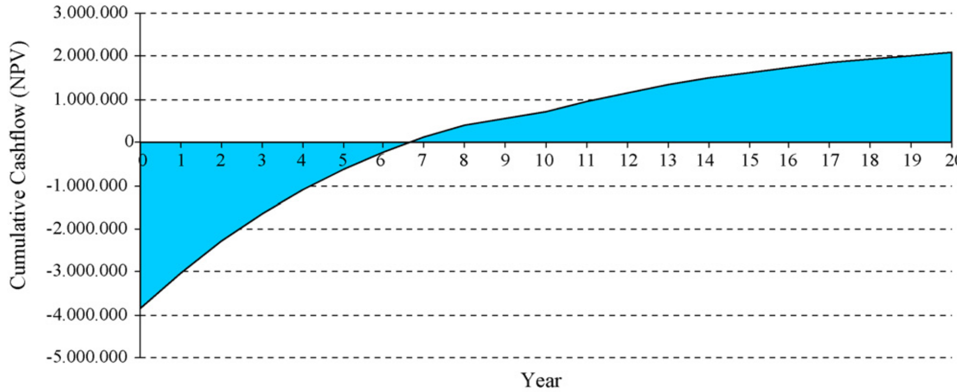

Fig. 8. Project's pay-back period on own capital.

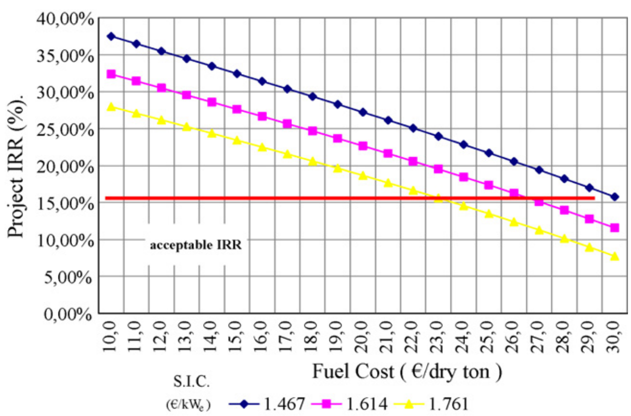

Fig. 9. Sensitivity analysis—Project IRR vs. feedstock fuel cost for different SICs.

given the narrow range of plant profitability, might have disastrous effects on project viability. Hence, careful negotiations have to be conducted with PPC, to secure the maximum possible penetration of the electricity to be delivered to the grid and to minimise related risks, derived from prolonged low energy demand periods on the island of Crete.

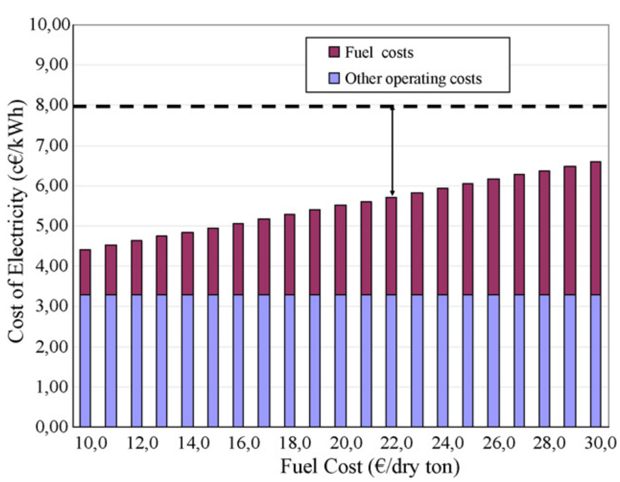

Fig. 10. Sensitivity analysis—Cost of Electricity (COE) as a function of fuel cost.

6. Conclusions

In this paper, the viability of an 8 MW_e biomass combustion plant was investigated. The main conclusions of this investigation are summarised below:

- Many reliable, quite efficient power plants, with net electrical efficiencies of approximately 23%, and with reasonable Specific Investment Costs (referred to Total Plant Cost figures), between €1600 and 1700 kW_e^{-1} (in the plant size range considered here), have been realised and are in smooth operation worldwide.
- The Total Operating Cost for the power plant under consideration is as high as ¢€5.6 kWh_e^{-1} delivered to the grid, with the fuel cost comprising approximately 37% of TOC (based on the fuel mix considered for Heraklion Prefecture). Due to the high sensitivity of the COE to the fuel cost, every possible effort should be undertaken to acquire lower cost feedstocks (for example, Exhausted Wet Olive Husk), or to secure the majority of the required fuel quantities through properly indexed, long-term fuel contracts.
- The project into consideration can be viable, provided that a 40% capital subsidy can be obtained. In this case, the project's pay-back period on own capital is 6.7 years, while the project's 10-year IRR is 20%.

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